

Docket: : A.09-12-002
Exhibit Number : _____
Commissioner : Michael R. Peevey
Admin. Law Judge : Maryam Ebke
DRA Project Mgr. : Yuliya Shmidt



**DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION**

**DRA TESTIMONY
ON PG&E'S APPLICATION FOR APPROVAL
OF THE MANZANA WIND PROJECT
AND ISSUANCE OF A
CERTIFICATE OF PUBLIC CONVENIENCE
AND NECESSITY**

****[PUBLIC VERSION]****

(A.09-12-002)

San Francisco, California
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CHAPTER 1 – OVERVIEW

A. SUMMARY OF PG&E'S PROPOSAL

Pacific Gas and Electric Company ("PG&E") requests the following in its Application 09-12-002 regarding the initial capital cost, the operation and maintenance ("O&M") cost, and the revenue requirement and ratemaking proposal for the Manzana Wind Project ("Project"):

- **Initial estimated capital costs of \$911 million** for the Project, for an assumed Project capacity of 246 MW and commercial operations date of XXXXXXXXX, consisting largely of XXXX million in payments to Iberdrola Renewables, Inc. and its subsidiary PPM Technical Services, Inc. (referred to collectively as "Iberdrola") under a Purchase and Sale Agreement ("PSA") and Project Completion Agreement ("PCA"). Under the PSA and PCA, Iberdrola and PPM Technical Services will develop and construct the Project, and PG&E will take ownership of the Manzana Project once it is commercially operational.
- **Operations and Maintenance (O&M) expenses** for the first three years of the Project's operations totaling XXXX million in year one, XXXX million in year two, and XXXX million in year three¹;
- **An initial annual revenue requirement** (based on projected capital costs and O&M expenses) for the first three years of the Project's operations of
 - XXXX million in year one,
 - XXXX million in year two, and
 - XXXX million in year three,

¹ PG&E Direct Testimony, Chapter 6.

1 **B. SUMMARY OF DRA’S RECOMMENDATIONS**

2 The Division of Ratepayer Advocates (“DRA”) has numerous concerns regarding
3 PG&E’s request for a Certificate of Public Convenience and Necessity and its request to
4 recover in rates PG&E’s costs to acquire, develop, and construct the Manzana Wind
5 Project as Utility Owned Generation. PG&E’s initial capital cost and initial annual
6 revenue requirements are excessive in many respects.

7 Further, PG&E’s estimated initial capital cost of \$911 million is virtually certain
8 to increase significantly due to delays—PG&E has assumed a commercial operations
9 date for the Project that is several months ahead of the current estimated date of
10 completion of the Tehachapi Renewable Transmission Project (“TRTP”) transmission
11 segment and substation that are required to complete turbine commissioning and connect
12 the Project to connect to the grid. These delays will significantly increase the total initial
13 capital costs and initial revenue requirements of the project. But under PG&E’s proposal,
14 ratepayers will bear all of the costs of such delays, virtually eliminating the incentives for
15 PG&E and the Project developers, Iberdrola and PPM Technical resources, to complete
16 the project with minimal cost increases. PG&E’s proposal also saddles ratepayers with
17 all of the risks of paying for generation that could ultimately be shuttered if a species of
18 bird protected under the federal or California Endangered Species Acts is killed due to
19 operation of the Manzana Wind Project.

20 DRA finds that, as proposed, the Project is not cost effective by comparison to
21 other wind resources. DRA accordingly recommends the Commission not approve the
22 Application as proposed.

23 Should the Commission decide to approve the Application, DRA recommends a
24 number of revisions:

- 25 • Reduction of initial capital costs from \$911.0 million to **XXXX**
26 million
- 27 • Reduction of recovered delay costs attributable to transmission
28 interconnection delays.

- 1 • All or a substantial portion of costs incurred due to the violation of
- 2 federal or state Endangered Species Acts – including foregone
- 3 profits due to reduction in generation – be borne by PG&E
- 4 • Contingency costs be reduced by XXXXXXXXXX
- 5 • Reduction of Operations & Maintenance costs to reflect adjustments
- 6 to payroll and contingency

CHAPTER 2 – ENVIRONMENTAL CONCERNS

The Manzana Wind Project will be located on approximately 7,000 acres in Kern County, in the Tehachapi region of California.⁷ According to the California Department of Fish and Game and the United States Fish and Wildlife Service, the Project site is within close proximity to critical habitat for the California condor as well as other endangered, rare or threatened species such as the Golden Eagle and the desert tortoise.⁸ Due to this proximity to known condor habitat, the Project could have substantial adverse impacts on this fully-protected endangered species.

Although the Kern County Planning Department has completed its environmental review of the Project and has approved Environmental Impact Statements for the Project, DRA is concerned that ratepayers bear substantial risk that the Project could be partially or completely shut down due to impacts on protected species, particularly the California condor. Simply having Kern County's seal of approval will not enable PG&E to continue operating the Project if a condor (or one of the other fully protected bird species that have been observed in the area) is killed by a turbine.

In order to mitigate potential impact on the protected California condors, PG&E has already altered the original footprint of the Project to eliminate three wind turbines that posed a potential hazard to California condors.⁹ PG&E will implement additional measures to avoid or reduce impacts on California condors.¹⁰ Based on the change in the Project's footprint and the implementation of these measures, PG&E states that it does not believe that operation of the Project would result in condor mortality or the

⁷ PG&E Direct Testimony, p. 1-2.

⁸ See Exhibit A, August 10, 2006 Fish and Game letter to Kern County Planning Department.

⁹ PG&E Direct Testimony, Appendix 3.2C, p. A-6; PG&E does not anticipate any additional turbines will need to be eliminated from the project due to a potential hazard to the California condor, or to any other species. Exhibit B - Data Response DRA_005-03.

¹⁰ See Reply of PG&E to the Motion of the Center for Biological Diversity for Inclusion of Environmental Considerations Within Scope of Proceeding, pp. 4-5.

1 unauthorized take of any protected species under the state or federal Endangered Species
2 Acts.¹¹

3 However, both the California Department of Fish and Game (“Fish and Game”)
4 and the United States Fish and Wildlife Service (“Fish and Wildlife”) have voiced serious
5 concerns that the Project could threaten the California condor and other listed and fully-
6 protected endangered species.¹² In a letter to the environmental consultant for the
7 original project developer, [REDACTED], Fish and Wildlife *disagreed*
8 with the consultant’s determination that the California condor is absent from the proposed
9 project.¹³ Rather, Fish and Wildlife noted that the Project is within two miles of critical
10 condor habitat and that condors have been identified within a half-mile of the northern
11 end of the proposed project. Fish & Wildlife similarly concluded that the Project is
12 located in close proximity to federally-designated critical habitat for the California
13 condor and is adjacent to an area used for captive breeding and release of the condors.¹⁴
14 PG&E has not offered any evidence or explanation to contradict the California and
15 Federal agencies’ conclusions.

16 Further, if it is determined that the California condors are in the Project site or the
17 Project results in a death (or “taking”) of a condor, the Department of Fish and Game
18 may require PG&E to shutter the Project:

19 Should it become apparent that condors are *utilizing* the Project site,
20 the Project proponent will need to coordinate immediately with the
21 Department and the USFWS to determine the steps necessary to
22 avoid “take” of this species. ***The loss of just one condor due to***
23 ***Project implementation is considered significant*** with respect to

¹¹ See Exhibit C - Data Responses DRA_005-02; Exhibit D - DRA_005-04.

¹² See Exhibit A - August 10, 2006 Fish and Game letter to Kern County Planning Department; Exhibit E - July 21, 2008, Fish and Game letter to Kern County Planning Department; Exhibit F- September 1, 2009 Fish and Wildlife letter to Sapphos Environmental, Inc., environmental consultant to original project developer enXco Development Corp.; Exhibit G - November 12, 2009 Fish and Wildlife letter to Kern County Planning Department. The Center for Biological Diversity, an intervenor in the proceeding has also raised similar concerns.

¹³ See Exhibit F - September 1, 2009 Fish and Wildlife letter to Sapphos Environmental, Inc., p. 2

¹⁴ See Exhibit E - July 21, 2008, Fish and Game letter to Kern County Planning Department, p. 3.

species recovery and may require operational modifications including but not limited to *complete or partial Project shut down*.¹⁵

PG&E’s current and planned further actions may reduce or avoid the potential impacts of the Project on California condors and other protected species. However, DRA is extremely concerned with the risk ratepayers face in the event that the Project is subjected to a partial or complete shut down due to California condor or other protected species issues. The Project is already ~~XXXXXXXXXXXXXXXXXXXXXXXXXXXX~~ ~~XXXXXX~~. A partial shutdown could drastically reduce the cost-effectiveness of the facility—or even worse, it could leave ratepayers footing the bill for the portions of the Project that essentially become a stranded asset.

Despite these risks to ratepayers, PG&E’s ratemaking proposal does not provide any protections for ratepayers in the event the project is delayed or commercial operations are stopped for reasons relating to an actual or potential violation of the federal or California Endangered Species Acts.¹⁶ On the other hand, PG&E has asked for shareholder protections in the form of pre-authorized Commission approval to pass through to ratepayers *all* cost increases that are caused by Project delays—whether they relate to endangered species or transmission delays.¹⁷ Therefore, DRA recommends that the Commission take steps to ensure that ratepayers are protected in the event that Project is partially or completely shut down due California condor or other protected species issues.

Additionally, DRA recommends that PG&E’s shareholders bear the full burden of any potential fines or penalties incurred due to impacts on protected species from the operation of the Project. The California condor is a protected species under both federal and state law, both of which can impose fines on any action that is defined as a “take” of

¹⁵ See Exhibit E – July 21, 2008, Fish and Game letter to Kern County Planning Department, pp. 3-4, emphasis added.

¹⁶ See Exhibit H – Data Response DRA_005-06.

¹⁷ Exhibit H - Data Response DRA_005-06 (stating that PG&E’s proposal to adjust initial capital cost and revenue requirements in the event of a delay in commercial operations would also apply to delays related to endangered species concerns).

1 a California condor, including the killing of a condor.¹⁸ Fines are also possible for the
2 unlawful “take” of the other protected species in the Project’s footprint due to the
3 operation of the Project.¹⁹

4 DRA assumes that PG&E will make all reasonable efforts to avoid the “take” of a
5 protected species during the construction and operation of the Project. However, the risk
6 of fines for the taking of a protected species does exist and ratepayers should not bear the
7 burden of these fines. If the Project’s generation was procured through a contract with a
8 private developer and not supplied by a utility-owned-generation facility, ratepayers
9 would not be responsible for paying fines related to the impacts of Project operation on
10 protected species.

¹⁸ California Fish & Game Code §§ 3511, 20008; Endangered Species Act 16 U.S.C. §§ 1532, 1538 and 1540.

¹⁹ “PG&E has not applied for, and at present does not intend to apply for, incidental take authorizations for any federal- or state-listed endangered species in connection with the proposed Manzana Wind facility.” Exhibit I - Data Responses DRA_005-01.

CHAPTER 3 - PG&E'S REQUEST TO RECOVER PROJECT COSTS AND PROPOSED RATEMAKING

A. PG&E'S REQUESTED COST RECOVERY FOR CAPITAL COSTS, O&M EXPENSES, AND INITIAL REVENUE REQUIREMENTS

1. PG&E's Estimated Initial Capital Costs

PG&E requests approval to recover \$911 million in initial capital costs for the Project. PG&E's \$911 million estimate includes the following components:

- (1) Purchase and Sale Agreement and the Project Completion Agreement Costs (\$XXXX million);
- (2) Transmission and Interconnection Costs (\$XXX million);
- (3) Project Management and Construction Costs (\$XXX million);
- (4) Owner's Contingency (\$XXX million);
- (5) Administrative and General Costs (\$XXX million); and
- (6) Allowance for Funds Used During Construction ("AFUDC") (\$XX million).²⁰

DRA recommends \$XXXX million for capital costs compared to PG&E's request of \$911 million. The reason for the difference is: DRA's recommended (1) reduction of the "PSA/PCA Costs" contingency factor to XX percent (\$XXX million); (2) elimination of \$XXX million included for "PG&E Costs" contingency amount as duplicative of other categories of capital cost and O&M expense contingency and (3) treatment of the Project Acquisition and Development Agreement as an expensed item rather than including it in rate base.

1.1. PSA/PCA Costs

The vast majority of the Project's initial capital costs are attributable to payments due to the developers, Iberdrola and PPM Technical Services (an affiliate of Iberdrola), under the Purchase and Sales Agreement and Project Completion Agreement ("PSA/PCA costs"). The PSA/PCA costs are \$XXX million—exclusive of any Change Scope Orders that may be required—and account for nearly XX percent of Project costs (XX percent when Overheads such as AFUDC and A&G are excluded). Yet none of the components

²⁰ PG&E Direct Testimony, p. 5-2 to 5-11.

1 of PSA/PCA costs are visible to the Commission or DRA—they are subsumed in a
2 “black box” and presented for wholesale approval without *any* review. DRA has
3 significant concerns regarding whether the costs Iberdrola is collecting under the
4 PSA/PCA are reasonable to include in PG&E’s proposed cost-of-service ratemaking—
5 particularly because the Project, as proposed, was *never subjected to a competitive*
6 *solicitation* and resulted from negotiations between PG&E and Iberdrola after Iberdrola
7 approached PG&E with an offer to sell the Project. DRA is also concerned that costs
8 PG&E is incurring and seeking to recover may be duplicative with services or activities
9 that should be provided by Iberdrola and PPM Technical Resources under the PSA and
10 PCA.

11 DRA and TURN are seeking information on the PSA/PCA costs (including the
12 costs of turbines), but have been unable to obtain such information to date. DRA issued
13 data requests to PG&E seeking information on the cost components of the PSA and PCA,
14 but PG&E has objected to providing that information.²¹ TURN has asked PG&E whether
15 it knows the cost of turbines purchased by Iberdrola for the Project or if PG&E has
16 otherwise reviewed pricing information for wind turbines. PG&E responded that it does
17 not know the price of the turbines purchased by Iberdrola and has not received price
18 quotes on wind turbines specific to the Project.²² PG&E has also stated that it never
19 received any cost information from Iberdrola during the negotiations,²³ which were
20 limited to a single-price negotiation.²⁴ Nor has PG&E analyzed the level of profit,
21 contingency and/or risk premium Iberdrola included in its Project price.²⁵

²¹ See Exhibit K - Data Response DRA_004-05; Exhibit L – Data Response DRA_004-06.

²² See Exhibit KK - Data Response TURN_005-03; Exhibit W – Data Response TURN_005-04.

²³ Counsel for DRA, Candace Morey, informed me that she received this information from counsel for PG&E, Cory Mason, during a telephonic communication on April 15, 2010.

²⁴ During a telephonic communication on April 20, 2010 between myself, counsel for DRA Candace Morey, counsel for PG&E Cory Mason and PG&E’s witness David Lewis, Mr. Lewis stated that he did not know or recall if the proposed installed price of the Project changed at all during the preliminary oral negotiations leading up to an agreement on a Term Sheet signed in June 2009.

²⁵ Exhibit M - Data Response TURN_001_Q06.

1 DRA has also served *subpoenas duces tecum* on Iberdrola and PPM Technical
2 Services for documentation of Project budget items, including the total costs for wind
3 turbines to be used to provide the baseline 189 MW of Project capacity and information
4 on whether Iberdrola's budget includes contingencies or staffing for engineering and
5 management positions that may be duplicative with PG&E's requests. While counsels
6 for Iberdrola and DRA had been discussing Iberdrola's responses to the request and DRA
7 sent Iberdrola a proposed Nondisclosure and Protective Agreement (to prevent the
8 disclosure of confidential information to PG&E or any other market participants),
9 Iberdrola filed a Motion to Quash the subpoenas on April 21, 2010, days before this
10 testimony was filed.²⁶ DRA therefore reserves all rights to submit supplemental
11 testimony to address the reasonableness of the total initial capital costs upon review of
12 information that may be provided by Iberdrola in connection with motion practice
13 seeking to compel Iberdrola to provide certain cost information about the Project.

14 **1.2. Owner's Contingency**

15 PG&E's has requested a total capital cost contingency of \$XXXX million,
16 approximately, XX percent of actual capital costs (excluding overheads such as AFUDC
17 and Administrative and General ("A&G") costs).²⁷ PG&E claims the contingency
18 reflects the uncertainty and risk associated with the scope and schedule of a project that
19 has not yet been developed. PG&E's requested contingency includes contingency on: (1)
20 Purchase and Sale Agreement ("PSA") and Project Completion Agreement ("PCA")
21 costs (XX percent), (2) transmission interconnection costs (XX percent) and (3) PG&E
22 costs (XX percent).²⁸

23 **DRA's Analysis and Recommendation**

24 While the overall requested contingency factor of XX percent may be consistent
25 with contingency factors approved by the Commission for turn-key non-renewable

²⁶ Counsel for DRA, Candace Morey, informed me that she discussed the subpoenas with Iberdrola's outside Counsel, Greg Wheatland, on April 12 and 14, 2010.

²⁷ PG&E Direct Testimony, pp. 5-6 to 5-8.

²⁸ Id.

1 utility-owned-generation, DRA has concerns that: (1) the level of the contingency for the
2 “PSA/PCA Costs” category is too high and (2) the “PG&E Costs” category is redundant
3 of other categories of capital cost and O&M contingencies.²⁹

4 PG&E’s ratemaking proposal includes a XX percent contingency for “PSA/PCA
5 Costs”, which amounts to \$XXX million for the 246 MW-sized Project.³⁰ As discussed
6 in Section 1.1 above, this entire category of cost is in a “black box”, with its components
7 not visible for review by the Commission or DRA. Therefore, it is impossible to
8 determine whether PG&E’s proposed contingency on these costs is reasonable or
9 duplicative of costs already included by Iberdrola in the PSA/PCA costs.³¹

10 Furthermore, it questionable whether a contingency should be applied to the entire
11 amount of PSA/PCA costs. As PG&E describes this contingency, it will only apply to a
12 subset of the services Iberdrola is providing under the PSA/PCA.³² PG&E indicates that
13 the contingency applied to this cost category will be used to fund change orders in the
14 event situations arise that require PG&E and Iberdrola to negotiate a change in scope
15 such as the work to be performed, contract price, or completion dates.³³ Not all aspects
16 of the Project may be subject to a change order³⁴, however, and the fixed contract costs
17 should not be subject to any contingency factor. For example, the Purchase and Sale
18 Agreement cost covers the acquisition of real estate interests in the Project site (including
19 transmission rights) and permitting activities, as well as a \$XX million payment to
20 XX.³⁵ It is difficult

²⁹The Commission adopted a 5.0 percent contingency for both PG&E’s Humboldt Power Plant in D.06-11-048 and SCE’s Mountainview Power Project in D.03-12-059.

³⁰ See Exhibit O - Data Response DRA_001-07, p. 4.

³¹ PG&E has not analyzed the level of profit, contingency and/or risk premium Iberdrola included in its Project price. Exhibit M - Data Response TURN_001-06.

³² See PG&E Direct Testimony at 5-7; Exhibit O - PG&E’s Data Response DRA_001-07.

³³ See Exhibit O - Data Response DRA_001-07, p. 4; PCA Sec. 1.1 (defining “scope change order” under the agreement).

³⁴ PG&E Direct Testimony at 2-9 to 2-11 (stating that under the PCA, XXXXXXXXXXXXXXXXXXXXXXXX
XXXXXX and emphasizing that Iberdrola has accepted “most risks and associated costs in developing and constructing the Project” with some exceptions described by PG&E).

³⁵ PG&E Direct Testimony, p. 2-6.

1 to understand how a change order will be necessary for these categories of costs—and if
2 these costs increase, they should be submitted to the Commission for a determination of
3 whether they are reasonable.³⁶ Furthermore, PG&E has requested authority to “update”
4 the Project’s initial capital cost and operations and maintenance estimates to reflect
5 change scope orders that PG&E may request.³⁷ This seems duplicative with also
6 allowing PG&E a contingency to fund change orders.

7 Additionally, a large proportion of the PSA/PCA costs are likely attributable to the
8 purchase cost of the 164 General Electric 1.5 SLE wind turbines.³⁸ Iberdrola bears the
9 responsibility of procuring and providing at least XXX of these turbines, regardless of
10 cost. Thus, while PG&E’s contingency is calculated based on an amount that includes
11 the purchase price of the turbines paid by Iberdrola there will not (or at least should not)
12 be any change in the costs of turbines to PG&E, and hence no contingency is necessary
13 on that portion of the PSA/PCA costs.

14 Most importantly, DRA assumes that the PSA/PCA costs include some profit for
15 Iberdrola, or at least some return on Iberdrola’s investment and the carrying cost of
16 maintaining the investment over the past several years. Again, since the entire cost
17 category is a black box, the Commission and DRA do not know what that amount of
18 profit is. Regardless, even if a contingency is applied to the PSA/PCA costs, it should
19 not be calculated based on an amount that includes a portion of profit or return on
20 investment for Iberdrola. The purpose of a contingency is to cover a certain amount of

³⁶ For example, see PSA Section 8.1, describing a procedure for XXXXXXXXXXXXXXXXXXXX
XX. This section of the PSA is
confusing, to say the least, but in the event PG&E is XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
XXXXXXXXXXXX, the Commission should review the expenditures for appropriate ratemaking
treatment.

³⁷ See PG&E Direct Testimony at 7-6.

³⁸ As explained in Chapter 3, Section 1.1.1, DRA has been unsuccessful in its attempts to obtain
information on the cost of the Project’s turbines, however, it is expected that turbine costs constitute a
large proportion of capital expenditures for the project. For example, a Department of Energy report
indicates that “virtually the entire recent rise in installed project costs...has come from turbine price
increases.” See Exhibit N – Department of Energy’s Annual Report on U.S. Wind Power Installation,
Cost, and Performance Trends: 2007 (May, 2008, available at <http://eetd.lbl.gov/ea/ems/reports/lbnl-275e.pdf>) p. 23.

1 uncertainty and risk associated with the scope and schedule of a project, *not to cover such*
2 *risks to the profit of the project developer*. Because PG&E's basis for the contingency
3 calculation is unsubstantiated, DRA recommends the use of a XXX percent contingency
4 factor for PSA/PCA costs, which amounts to approximately \$XXX million. This level of
5 contingency should provide adequate funds to deal with any change orders, particularly
6 in light of PG&E's request for authority to submit change order costs for recovery
7 through an advice letter process (although DRA recommends that change order costs be
8 submitted for approval through an application). Furthermore, a lower contingency will
9 reduce the levelized cost of energy for the Project, which is currently XXXXXXXXXXXX
10 than comparable wind facilities.

11 Second, DRA recommends eliminating the contingency on "PG&E Costs" as
12 redundant to other categories of capital cost and O&M contingencies. PG&E requests a
13 PG&E Costs contingency of \$XXXX million.³⁹ PG&E claims the contingency for the
14 PG&E Costs category "will be used to fund items such as the need for additional
15 resources to assure high quality design and construction; higher than expected labor rates
16 and third party services and material; and higher than expected costs and/or longer than
17 expected timeframe for hiring the O&M staff."⁴⁰

18 The items included in PG&E's description are already covered by other areas of
19 capital cost and O&M expense contingency. For example, PG&E's requested O&M
20 Labor contingency of XX percent should address "higher than expected labor rates, third
21 party services; and higher than expected costs and/or longer than expected timeframe for
22 hiring the O&M staff." Additionally, the PSA/PCA costs category of contingency should
23 easily address the "need for additional resources to assure high quality design and
24 construction" as well as "higher than expected material" costs.⁴¹ Therefore, DRA
25 recommends the Commission not approve the contingency amount for "PG&E Costs" of
26 \$XXX million because it is duplicative of other categories of contingency.

³⁹ See Exhibit O - Data Response DRA_001-07, p. 4.

⁴⁰ Id.

⁴¹ Id.

1 In conclusion, DRA’s recommended total for contingency costs after adjusting the
2 PSA/PCA Costs category and eliminating the PG&E Costs category is \$XXX million.

3 **1.3. Costs Relating to the** XXXXXXXXXXXXXXXX
4 XXXXXXXXXXXXXXXX with the XXXXXXXXXXXX
5 XXXXXXXX

6 PG&E’s initial capital cost estimate includes a payment of *** BEGIN
7 PROPRIETARY***

8
9 .⁴²

10
11
12
13
14
15 .⁴³

16 *** END PROPRIETARY***⁴⁴

17 **DRA’s Analysis and Recommendation**

18 DRA recommends that this \$XX million payment be removed from rate base and
19 instead be treated as an expense. PG&E should not receive a rate of return by placing
20 this payment into rate base, because it primarily exchanges what would have been an

21 XX. PG&E elected to pay XX
22 XX
23 XX
24 XX
25 XXXXXXXXXXXXXXXXXXXX⁴⁵XXX

⁴² Exhibit P - Data Response DRA_001-17.

⁴³ Exhibit Q - Data Response DRA_001-16-Attachment1.pdf (Execution Copy of the Second Amendment to Amended and Restated XX) at p. 2.

⁴⁴ Id. p. 5.

⁴⁵ See, e.g., Exhibit R - PGE/MAN 000019-20 (email exchange outlining XXXXXXXXXXXXXXXXXXXXXXXX

1 XX
2 XX
3 XX,
4 XXXXXXXXXXXXXXXXXXXXXXXX.⁴⁶

5 Ratepayers, however, are not indifferent between the two options. PG&E
6 proposes to put the \$XXXXXXX payment into rate base—and to make a rate of return on
7 what would have been a XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
8 the Project. Further, PG&E has not demonstrated any estimated XXXXXXXXXXXXXXXX
9 that can be attributed to XXXXXX XXXXXXXXXXXXXXXXXXXXXXXX
10 XXXXXXXXXXXXXXXX. DRA therefore recommends that the Commission allow
11 PG&E to recover XXXXXXXXXXXXXXXX as a pass-through expense, amortized over three
12 years. While this will increase the initial revenue requirement in the initial three years of
13 the Project, ratepayers will ultimately pay less than if the payment is added to rate base.

14 1.4. Overheads

15 PG&E requests an AFUDC amount of \$XXXX million, based on its authorized
16 weighted average costs of capital of 8.79 percent.⁴⁷ DRA agrees with PG&E's use of
17 8.79 percent as the AFUDC capital rate through December 31, 2011. As discussed in
18 Section B below, DRA recommends an alternative AFUDC rate for any period of delay
19 beyond December 31, 2011. Furthermore, DRA's recommended capital costs for the
20 Project will result in a lower AFUDC.

21

XXX,
XXX and PGE/MAN
000030-31 (email exchange between PG&E and Iberdrola outlining XXXXXXXXXXXXXXXX
XXX
XXXXXXXXXXXX).

⁴⁶ See Id.; see also Exhibit S - Data Response DRA_001-Q15-Attachment1.pdf (Excerpts from Execution Copy of the Amended and Restated XXXXXXXXXXXXXXXX relating to the XXXXXXXXXXXXXXXX) Sections 2.3.8 (a) (Section 2.3.8(a)(ii) XXXXXXXXXXXXXXXX).

⁴⁷ PG&E Direct Testimony, pp. 5-8 to 5-9.

1 **2. PG&E’s Estimated Operations and Maintenance**
2 **(“O&M”) Expenses**

3 This section provides DRA’s assessment of the operations and maintenance
4 (“O&M”) costs in PG&E’s application for the Manzana Wind Project. PG&E has
5 requested approval of O&M costs for (1) pre-commercial operations, (2) post-
6 commercial operations and (3) potential construction delay. DRA recommends a
7 reduction to PG&E’s payroll request and O&M contingency as well as placing any
8 approved O&M contingency in a one-way balancing account.

9 **2.1. Pre-Commercial Operations Costs**

10 PG&E’s total request for pre-commercial operations costs is \$XXXXXX, which
11 includes both labor and non-labor components.⁴⁸ PG&E indicates that the pre-
12 commercial operations costs will be used for staffing requirements, training and materials
13 needed to operate the Project prior to commercial operation.⁴⁹ PG&E indicates that it
14 will start incurring these costs approximately nine months in advance of commercial
15 operation.⁵⁰

16 **2.2. Post-Commercial Operations O&M Costs**

17 PG&E has requested Commission approval of post-commercial operations costs of
18 \$XXXXXX, \$XXXXXX and \$XXXXXX respectively for the first three years of
19 operations.⁵¹ These post-commercial operations costs include costs in the following
20 categories: (1) Labor, (2) Consumables, (3) Service Agreement, (4) Balance of Plant
21 Maintenance and (5) Contingency. DRA recommends: (1) a reduction in the number of
22 wind technicians, (2) placing any O&M contingency in a one-way balancing account and
23 (3) reductions to two categories of O&M contingency.

⁴⁸ PG&E Direct Testimony, p. 6-2.

⁴⁹ Id. at 6-3 to 6-4.

⁵⁰ Id.

⁵¹ PG&E Direct Testimony, p. 6-5.

2.2.1. Payroll

PG&E requests XX wind technician positions for the Project.⁵² PG&E's staffing request is based on industry benchmarking studies on data provided by three wind turbine manufacturers and developers as well as by three wind farm owners.⁵³ The data demonstrated that a typical wind farm is staffed with one wind technician for every XXX XX wind turbines. Based on a 246 MW project capacity (164 turbines), XX wind technicians is a ratio of one technician for every XX turbines.

As proposed by PG&E, the levelized cost of energy for the Project is XXXXXX XXXX than comparable wind facilities. Even if the Commission approves the Project, it should reduce component costs to ensure a reasonable levelized cost of energy for a ratepayer-funded project.

Therefore, DRA recommends that Commission approve a staffing level for wind technicians based on XX technician for every XX turbines. This will result in a reduction of PG&E's request for wind technicians by one position to XX wind technician positions. This staffing level is within the range provided by the benchmarking studies and will not only reduce O&M payroll costs, but will also reduce other associated vehicle, training and equipment costs. PG&E can update staffing levels in its next General Rate Case after it has commenced operations of the facility.

2.2.2. O&M Contingency

PG&E requests O&M contingency costs of \$XXXXX, \$XXXXX and \$XXXXX respectively for the first three years of operations.⁵⁴ The contingency costs pertain to three areas: (1) Labor, (2) Balance of Plant Maintenance and (3) Service Agreement. PG&E requests contingency factors of XX percent for Labor, XX percent for Balance of Plant Maintenance and XX percent for Service Agreement. DRA recommends: (1) that the Commission place PG&E's requested contingency costs in a one-way balancing

⁵² Id.

⁵³ Exhibit T - Data Response DRA_003-01.

⁵⁴ Exhibit O - Data Response DRA_001-07.

1 account; and (2) a reduction of the contingency factors for both Balance of Plant
2 Maintenance and Service Agreement to XX percent.

3 Since the Manzana Wind Project will be the first large wind project operated by
4 PG&E, it is just as likely that PG&E's assumptions could result in an overestimation of
5 its actual costs as in an underestimation of the O&M costs, an uncertainty that is inherent
6 to the future test year ratemaking that PG&E proposes for the Project. "This uncertainty
7 can as easily result, in the short-run, in increased shareholder earnings as in unrecovered
8 shareholder costs."⁵⁵ Therefore, a contingency would not appear warranted for the
9 Project under normal circumstances.

10 However, the Commission will be adopting an initial revenue requirement in this
11 proceeding several years in advance of the Project's commercial operation, and without
12 an opportunity for PG&E to update the O&M estimates on the basis of actual plant
13 operation. PG&E filed its last General Rate Case application for the 2011 test year on
14 December 21, 2009.⁵⁶ This is well before April 15, 2012, the current earliest reasonable
15 operational date for the Project.⁵⁷ Based on the conventional three-year GRC cycle,
16 PG&E's next GRC will be for test year 2014, almost two years after the expected
17 operational date for the Project. Therefore, the earliest GRC opportunity to update the
18 Project's O&M costs after it is fully operational will not be until December 2012 for
19 purposes of test year 2014.

20 In order to address this mitigating circumstance, DRA recommends that the
21 Commission place any authorized O&M contingency amount in a one-way balancing
22 account, which PG&E may recover if and when the funds are actually expended. This
23 treatment of O&M contingency is consistent with the Commission's treatment of similar
24 expenses for PG&E's Colusa and Humboldt generation facilities in D.06-11-048.⁵⁸

⁵⁵ D.06-11-048, p. 29.

⁵⁶ See A.09-12-020.

⁵⁷ Exhibit U - SCE's Response to DRA Data Request TRTP DRA-04.

⁵⁸ D.06-11-048, p. 30.

1 In addition to its recommendation that the Commission place PG&E's requested
2 O&M contingency amount in a one-way balancing account, DRA also recommends a
3 reduction to the contingency factors for: (1) Balance of Plant Maintenance and (2)
4 Service Agreement. PG&E requests contingency factors of XX percent for Balance of
5 Plant Maintenance and XXX percent for Service Agreement, both significantly higher
6 than the X percent contingency factor requested for Labor. PG&E indicates that there is
7 uncertainty associated with all three areas, but does not provide convincing evidence to
8 support contingency factors for Balance of Plant Maintenance and Service Agreement
9 that are XX and XX percent higher, respectively, than the contingency factor for Labor.⁵⁹

10 As discussed above, it is just as likely PG&E's assumptions could result in an
11 overestimation of its actual costs as in an underestimation of the O&M costs. This
12 supports limiting all O&M contingency factors to modest levels. Furthermore, since the
13 levelized cost of energy for the Project is XXXXXXXXXXXX than comparable wind
14 facilities, it is important to limit costs wherever possible to ensure a reasonable levelized
15 cost of energy for a ratepayer-funded project.

16 Therefore, DRA recommends that the Commission limit the contingency factors
17 for Balance of Plant Maintenance and Service Agreement to XX percent, the proposed
18 contingency factor for Labor. Based on these adjustments, DRA recommends O&M
19 contingency costs of \$XXXXXX, \$XXXXXX and \$XXXXXX respectively for the first three
20 years of operations.

21 3. Initial Revenue Requirement and Ratemaking

22 The estimated initial capital cost of the Project is \$911 million. PG&E requests an
23 initial revenue requirement of \$XXXX million for the first year of commercial operations
24 of the Project.⁶⁰ The initial revenue requirement will begin to accrue in PG&E's Utility
25 Generation Balancing Account as of the first date of commercial operation.

⁵⁹ PG&E Direct Testimony, p. 6-10 to 6-11; Exhibit O - Data Response DRA_001-07.

⁶⁰ PG&E Direct Testimony, p. 7-1.

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PG&E’s proposed decommissioning accruals total \$XXXXXX each year in the initial annual revenue requirement for the Project. This revenue requirement is based on PG&E’s estimates of the costs in 30 years to decommission 164 turbines (assuming a 264 MW Project) and to complete site restoration. PG&E’s proposal is based on estimated decommissioning costs totaling \$XXXXX per turbine—for XXXXXXXXXXXXXXXXXXXX
XX
XXXXXXXXXXXXXXXXXXXXXXXXXXXX.⁶¹ PG&E does not explain or rationalize the costs it has assigned to each of these activities, and instead states that it will include a “more detailed decommissioning cost estimate” in the general rate case following completion of the Project.⁶² Nor has PG&E indicated the likelihood that the Project *will actually need to be* fully decommissioned and the site restored in 30 years. It is at least possible that PG&E could explore options for continuing Project operations or Project redevelopment (e.g., through repowering or other efforts).

DRA recommends that the \$XXXX per year of decommissioning costs should be allowed from PG&E's initial revenue requirement. Rather, recovery for decommissioning costs should be delayed until additional information is available on the reasonable estimated costs for decommissioning and the likelihood that the plant will need to be decommissioned and the site restored. Forecasting decommissioning costs that will be incurred 20 to 30 years in the future (depending on reasonable estimated plant useful life) is inherently imprecise and speculative, and PG&E has not provided any reason why decommissioning costs should begin accruing

⁶² PG&E Direct Testimony at 5-9, 7-12; see also Exhibit X - Data Response TURN_001-19 p. 3; Exhibit Y - DRA 001-09.

1 from year one of Project operations. PG&E's estimate may also be overstated. If the
2 Project capacity is only 189 MW and XX fewer turbines are installed, the total nominal
3 decommissioning costs could be as much as \$XXXXXX lower than PG&E's estimate,
4 which is based on an assumed project capacity of 246 MW. PG&E should not be given
5 approval to recover decommissioning costs for turbines that may never be erected.

6 There is no reason for PG&E to begin accrue decommissioning costs
7 immediately—when under PG&E's proposal decommissioning will not occur until 30
8 years after the plant is brought into service. That affords plenty of time for PG&E to
9 recover decommissioning costs from the ratepayers who are actually benefiting from
10 energy deliveries from the Project. It also affords necessary time for PG&E to prepare—
11 and consumer groups to evaluate—a more detailed and substantiated decommissioning
12 cost proposal. Delaying the recovery of decommissioning costs will both reduce the
13 Project's revenue requirements in the initial few years and will ensure that ratepayers
14 only pay for decommissioning that is likely to occur and costs that are based on
15 substantiated, reasonable estimates. DRA would not oppose PG&E's submitting
16 decommissioning costs in connection with its next General Rate Case if PG&E has
17 completed additional studies on decommissioning costs at that time.

19 **B. PG&E'S REQUEST FOR AUTHORITY TO INCREASE PROJECT COSTS** 20 **AND REVENUE REQUIREMENTS**

21 PG&E's ratemaking proposal requests authorization to increase the total initial
22 capital costs and initial O&M expenses for the Project—and accordingly to increase the
23 Project's initial revenue requirements. PG&E proposes direct inclusion in the Manzana
24 Wind Project memorandum account of cost increases due to delay in commercial
25 operations *without any further Commission review or approval*. For other potential cost
26 increases, PG&E would submit the proposed increases to the Commission for pre-
27 approval under an expedited advice letter process.⁶³ Although, DRA does not oppose
28 reasonable revisions to PG&E's cost estimates, DRA does oppose PG&E's request for a

⁶³ PG&E Direct Testimony, pp. 7-3 to 7-4.

blank check for delay costs—which are virtually certain to occur and cost at least \$XX million per month of delay.⁶⁴ DRA also opposes PG&E’s proposal to submit certain other cost increases via an expedited advice letter process. DRA recommends that the Commission instead authorize such proposed cost increases through an application process.

Table 3-1 – Summary of DRA Recommendations on Requested Authority to Increase Project Costs and Revenue Requirements

Category of Revision	PG&E’s Requested Treatment	DRA’s Recommended Treatment	DRA’s Reasoning for Different Treatment
Delay Costs	Expedited Advice Letter for Delay Costs after 12/31/2011	PG&E recovers delay costs based on the 90-day commercial paper rate, not as AFUDC	Reflects more accurate commercial operation date and creates incentive to reduce delay in commercial operations.
Operational Enhancements	Expedited Advice Letter	Application	Level and nature of costs uncertain. Prudency review of cost necessary.
Changes in Law or Factors beyond PG&E’s Control	Expedited Advice Letter	Application	Level and nature of costs uncertain. Prudency review of cost necessary.
Updated Revenue Requirement Factors	Expedited Advice Letter	Expedited Advice Letter	N/A
Transmission Upgrades	Reflect in Manzanita Wind Project memorandum account	Reflect in Manzanita Wind Project memorandum account	N/A

⁶⁴ See PG&E Direct Testimony 5-9 to 5-10 and 7-16, lines 12-14.

Changes in Renewable Tax Credits	Pre-Approval for authority to (1) elect between ITC and PTC; (2) revise cost due to modified ITC or PTC; (3) proceed with Project without ITC or PTC.	Tier 2 or higher for ITC or PTC election and revision due to modified ITC or PTC. DRA opposes authorizing the Project if it is ineligible for the ITC or PTC (if the Project is delayed beyond 12/31/2011 and the ITC or PTC is not extended).	All three decisions have serious implications regarding cost-effectiveness of the Project and therefore require interested party input prior to approval by the Commission.
Decreased Project Capacity	Pre-Approval for authority to reduce costs	Pre-Approval for authority to reduce costs with modifications	Per-MW cost reduction should be increased if leased land is not used for facilities; re-calculation may be necessary in light of Commission's ratemaking treatment for other costs.

1. PG&E's Requests for Authority to Increase Initial Capital Costs and O&M Expenses

PG&E requests authority to revise the initial capital cost and O&M expense estimates under the following circumstances: (1) delay in commercial operation, (2) operational enhancements, (3) change in project capacity and (4) changes in law or factors beyond PG&E's control.⁶⁵ DRA opposes PG&E's proposal regarding increased initial capital costs due to delays in commercial operation. While DRA does not generally oppose the Commission authorizing PG&E to revise the Project's initial capital

⁶⁵ PG&E Direct Testimony, pp. 7-5 to 7-6.

1 cost based on operational enhancements or changes in law other factors beyond PG&E's
2 control; these revisions should not be authorized through an advice letter process and
3 should be subject to an application process.

4 **1.1. Cost Overruns for Delays in Commercial Operations**
5 **Beyond December 31, 2011**

6 PG&E's cost estimates and proposed ratemaking rely on an assumed commercial
7 operation date for the Project of **December 31, 2011**.⁶⁶ And as PG&E itself has
8 emphasized, completion of the Whirlwind Substation by **XXXXXXXXXXXX** is critical to
9 achieving commercial operation of the Manzanita Wind Project by December 31, 2011.⁶⁷
10 But interconnection of the Whirlwind Substation is not expected to be completed until
11 March 2012—meaning that Project costs are virtually certain to escalate significantly due
12 to delays in commercial operations. Even under optimistic estimates the Project is not
13 likely to begin commercial operations until at least **XXXXXXXXXXXX** and could easily be
14 delayed until **XXXXXXXXXXXXXXXXXXXX**.

15 At the same time, PG&E asks the Commission for a blank check to pass onto
16 ratepayers *all* cost increases that are attributable to pushing back the date of commercial
17 operations for transmission-based delays. PG&E has not even estimated what the total
18 additional costs may be under the highly-likely event of such delays. Instead, PG&E
19 requests blanket pre-approval to increase the Project's initial capital costs by **\$XX** million
20 per month of delay (attributable primarily to **XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX**
21 **XX**) *plus* any
22 increased costs that PG&E **XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX** for delays
23 due to completing transmission interconnection.⁶⁸

24 **DRA's Analysis**

25 Delivering the full capacity of the proposed Project to the grid will require several
26 segments of Southern California Edison Company's ("SCE") Tehachapi Renewable

⁶⁶ PG&E Direct Testimony, p. 5-9.

⁶⁷ Exhibit Z – Data Response TURN_001-11.

⁶⁸ See PG&E Direct Testimony 5-9 to 5-10 and 7-16, lines 12-14.

1 Transmission Project (“TRTP”) to come online.⁶⁹ Specifically, the Project requires the
2 completion of the Whirlwind Substation, which is part of Segment 9, as well as Segment
3 4.⁷⁰ Although the anticipated completion date of the Whirlwind Substation is April 2011,
4 Segment 4 of the Tehachapi Renewable Transmission Project is currently projected to
5 come online in **March of 2012**—**XXXXXXXX** after the date built into PG&E’s
6 assumed commercial operations date.⁷¹

7 Transmission interconnection is required not only to sell power from the Project
8 but also to provide backfeed power that is needed to commission the wind turbines.
9 During negotiations over the guaranteed substantial and final completion dates of the
10 project, Iberdrola stated that **XX**
11 **XX**.⁷² Iberdrola
12 estimated that it would require **XXXXXX** to commission the base 126 turbines required for
13 a 189 MW project⁷³ (a 246 MW Project will utilize 164 turbines⁷⁴). The final project
14 completion schedule (Exhibit W of the PCA) allows Iberdrola **XXXXXX** from the date of
15 “guaranteed” transmission interconnection to the “Expected” (or target) Substantial
16 Completion date, however.⁷⁵ **XX**
17 **XX**
18 **XXXXXXXXXXXXXXXXXXXXXXXXXXXX**⁷⁶

⁶⁹ The Commission approved a Certificate for Public Convenience and Necessity for the Tehachapi Renewable Transmission Project in Decision 09-12-044.

⁷⁰ See Exhibit AA - Data Response DRA_002 Oral-01, p. 1.

⁷¹ See Exhibit U - SCE’s Response to DRA Data Request TRTP DRA-04-Q01 (stating that as of February 22, 2010, SCE assumes an operating date of March 2012 for Segment 4).

⁷² See Exhibit BB - PGE/MAN 000767-770 at 768 (email exchange between PG&E and Iberdrola, “**XXX XXX**”).

⁷³ See Exhibit CC - PGE/MAN 000774-775 (stating Iberdrola’s belief that “**XXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXX**”).

⁷⁴ See PG&E Direct Testimony Appendix 3.1 (IE Report) at 3.

⁷⁵ See PCA Exhibit W (Project Schedule). “Substantial Completion” requires, among other things, that **XX**. PCA Sec. 7.5(a).

⁷⁶ PCA Sec. 1.1 (definitions) and Exhibit W (Project Schedule); Exhibit DD - Data Response DRA_001-21; and PSA Sec. 7.13(b). The Guaranteed Substantial Completion Date is **XXXXXXXXXX** for a 189 MW project **XXXXXXXXXX** for a 246 MW project, but is based on a guaranteed interconnection

1 Thus, even assuming that the Whirlwind Substation and Segment 4 are completed
2 and online by March 1, 2012, under a highly optimistic (and thus conservative) estimate
3 the turbines would not be commissioned for an additional XXXXXXXXXXXXXXXXXXXX-
4 XXXXXX at the earliest.⁷⁷ Under this scenario, initial capital costs of the Project would
5 increase by at least \$XXXXXX (189 MW) to \$XXXXXXXXXX (246 MW) from PG&E's
6 initial cost estimates, corresponding to an increase of \$XXXXXXXXXX in the Project's
7 revenue requirement in year 1.⁷⁸ Under its proposal, PG&E would *also* recover unknown
8 XX without any further
9 reasonableness review.

10 Considering slightly less optimistic scenarios, Segment 4 may not be completed
11 until the latter part of March 2012 or Iberdrola might not XXXXXXXXXXXX
12 XXXXXXXXXXXXXXXXXXXX—which is feasible considering that the PCA's Project
13 Schedule allows Iberdrola XXXXXX months between transmission interconnection and
14 Guaranteed Substantial Completion. Commercial operations could, therefore, easily be
15 delayed until XXXXXXXXXXXXXXXXXXXXXXXX. Under this scenario, initial capital
16 costs of the Project would increase by at least \$XXXXXX (189 MW online in XXXXXX)
17 to \$XXXXXX (246 MW online in XXXXXX) from PG&E's initial cost estimates.⁷⁹

facilities date of XXXXXXXXXXXX and an "expected" interconnection facilities date of XXXXXXXXXXXX,
and may be XX. Further, the Guaranteed Final
Completion date is XXXXXX after the date of Substantial Completion. See PCA Sec. 7.8; see also
Exhibit EE – PGE/MAN 000771-773.

⁷⁷ PG&E and Iberdrola could find alternative means to commission turbines; however, PG&E would be
XX. PCA
Sec. 6.1(d) (XX
aXXs). PG&E has not provided any
information to indicate whether alternative commissioning would be a viable or cost-effective means to
reduce costs associated with transmission delays.

⁷⁸ See Exhibit FF - Data Responses to DRA_001-08 (showing monthly increases in total capital costs and
corresponding increases in revenue requirements. I multiplied these monthly increases by XX for a delay
from December 31, 2011 to XXXXXXXXXXXX). See also Exhibit GG -DRA_004-Q1-CONF-
Attachment01-Rev01.

⁷⁹ See Exhibit FF - PG&E's Responses to DRA_001-08 (showing monthly increases in total capital costs
and corresponding increases in revenue requirements. I multiplied these monthly increases by XX for a
delay to XXXXXXXX, and by XX for a delay to XXXXXXXXXXXX). See also Exhibit GG - DRA_004-
Q1-CONF-Attachment01-Rev01.

PG&E would therefore increase the Project's initial revenue requirement in year one by \$XX(189 MW online in XXXXXX) XXXXXXXXXX (246 MW online in XXXXXX).⁸⁰

Again, PG&E would *also* recover unknown XXXXXXXXXXXXXXXXXXXXXXXXXXXX
XXXXXXXXXXXXXXXXXX.

Further, the additional costs PG&E may incur [REDACTED] [REDACTED] are unknown at this time—indeed, PG&E claims to have not completed *any* likelihood or cost implication analysis for [REDACTED]

[REDACTED].⁸¹ [REDACTED]

[REDACTED]⁸² PG&E also admits that it [REDACTED]

[REDACTED]⁸³ PG&E’s only approach to containing [REDACTED] costs seems to be a hope [REDACTED].⁸⁴ But the [REDACTED]

[REDACTED]

S[REDACTED]

[REDACTED].⁸⁵ These [REDACTED]

⁸⁰ See Exhibit FF - Data Responses to DRA_001-08 (showing monthly increases in total capital costs and corresponding increases in revenue requirements. I multiplied these monthly increases by XX for a delay from December 31, 2011 to XXXXXXXXXX). See also Exhibit GG - DRA_004-Q1-CONF-Attachment01-Rev01.

⁸¹ See Exhibit HH – Data Response TURN_001-07 [REDACTED]
[REDACTED] and stating that PG&E has not done any
likelihood and/or costs implication analysis for potential [REDACTED]
[REDACTED]; Exhibit II - Data Response
TURN_001-20.

[illegible]

⁸³ See Exhibit LL – Data Response DRA 004-12.

⁸⁴ See Exhibit HH – Data Responses TURN_001-Q07; Exhibit LL – Data Response DRA_004-12; Exhibit JJ - DRA 001-22.

⁸⁵ See PCA Sec. 6.1(b).

1 XXXXXXXX, which amount to about XXXX percent of the total delay costs.⁸⁶ At the
2 same time, Iberdrola would be XX
3 XX.⁸⁷ This
4 structure gives Iberdrola every incentive to XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
5 XX.

6 DRA's Recommendation

7 DRA opposes having ratepayers bear the full burden of increases to capital costs
8 due to delay, when it was PG&E who agreed to the highly unlikely schedule for
9 achieving commercial operations and PG&E who will manage construction and
10 "oversee[] the entire execution of the Project and the [Project Completion Agreement]
11 PCA."⁸⁸ PG&E agreed to a payment schedule and contract terms that XXXXXXXX
12 XX as early as
13 possible, rather than on a schedule that XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
14 XX
15 XXXXXXX.⁸⁹ PG&E should therefore bear the risk and consequences if Iberdrola XXXX
16 XX
17 XXXXXXX.⁹⁰

18 Accordingly, DRA recommends that Commission not allow PG&E to recover
19 additional AFUDC costs due to a delay in commercial operations attributable to
20 transmission interconnection delays at its authorized cost of capital rate of 8.79 percent.
21 Instead, the AFUDC amount for such delays should be calculated based on the 90-day

⁸⁶ See Exhibit FF - Data Response DRA_001-Q08 (I compared the per-month increases in AFUDC costs to total per-month increases in capital expenditures for the 189 and 249 MW project scenarios).

⁸⁷ See PCA Sec. 6.1; 9.2 (required XXXXXXXX include cost increases caused by XXXXXXXX XX XX).

⁸⁸ PG&E's Direct Testimony, pp. 5-4.

⁸⁹ Indeed, as PG&E believes that Iberdrola sought to sell the Project to PG&E in order to XXXXXXXX XX XXXXXXXXXXXXXXXX Exhibit MM – Data Response TURN_001-03.

⁹⁰ See e.g. Exhibit JJ – Data Response DRA_001-22.

1 commercial paper rate. If PG&E is allowed to recover AFUDC costs, it will essentially
2 be incentivized to *create* delays rather than avoid them. Further, any costs incurred due to
3 XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX may be funded from
4 PG&E's requested *contingency* on the PSA/PCA costs, but should not be separately
5 approved by the Commission (let alone through an expedited advice letter process).
6 Alternatively, for cost increases due to XXXXXXXXX, DRA recommends requiring
7 PG&E to track costs in a memorandum account, subject to later approval via the Tier 3
8 advice letter process so that the Commission (and consumer groups) may consider
9 whether the delay and specific costs incurred are reasonable.

10 Finally, if the project capacity is less than 246 MW, any delay costs PG&E is
11 authorized to recover should be reduced and prorated to reflect the final project capacity
12 according to PG&E's responses to DRA_001_Q08 and DRA_001_Q23.

13 1.2. Operational Enhancements

14 PG&E requests authority to revise the initial capital cost of the project for
15 operational enhancements that "may increase the efficiency of operations of the
16 facility."²¹ PG&E would seek Commission pre-approval for the revision to the initial
17 capital cost for operational enhancements via expedited advice letter.

18 DRA's Analysis and Recommendation

19 It is not evident what the "operational enhancements" to the Project will be, how
20 much they will cost or whether they will be cost-effective. The cost of operational
21 enhancements could be significant and therefore merit a higher level of scrutiny than the
22 advice letter process.

23 Furthermore, PG&E has requested a XX percent contingency on Purchase and
24 Sales Agreement ("PSA")/ Project Completion Agreement ("PCA") costs. Although
25 DRA recommends a lower contingency factor of XX percent for these costs, either factor
26 adopted by the Commission should provide PG&E additional flexibility for increased
27 costs due to operational enhancements.

²¹ PG&E Direct Testimony, pp. 5-10, 7-6.

1 Therefore, DRA recommends that the Commission require that any revision to the
2 initial capital cost of the Project due to operational enhancements is done through the
3 application process.

4 **1.3. Changes in Law or Factors beyond PG&E’s Control**

5 PG&E requests Commission authority, via an expedited advice letter filing, to
6 revise the capital cost estimate if new or modified regulatory requirements, such as
7 permit conditions, changes in law or regulation or changes in the building code, or other
8 external events, such as a force majeure event, cause the costs of the Project to exceed the
9 \$911 million cost estimate.²²

10 **DRA’s Analysis and Recommendation**

11 Although DRA does not dispute that revisions due to changes in law or other
12 external factors may be necessary, DRA opposes the use of the advice letter process for
13 revising the capital cost estimate due to such circumstances. The advice letter process is
14 not appropriate when no record exists to determine the reasonableness of additional
15 capital costs associated with changes in law or other external factors. The level of costs
16 is too uncertain to review under the lower level of scrutiny required by the advice letter
17 process. The advice letter process is only appropriate when a Commission decision has
18 approved the requested action.²³ Therefore, DRA recommends that the Commission grant
19 authority for such revisions through only the application process.

20 **2. PG&E’s Requested Increases to the Initial Revenue** 21 **Requirement**

22 PG&E requests authority to revise the initial revenue requirements for the project
23 to reflect possible increases due to: (1) updated revenue requirement factors,
24 (2) transmission upgrades and (3) changes in renewable tax credits.

²² PG& Direct Testimony, p. 7-6.

²³ See D.06-11-048, p. 25, “[I]t is appropriate to use the advice letter process for adjustments upon payment or receipt of incentives under the pre-approved terms of the contract.”

2.1. Updated Revenue Requirement Factors

Prior to commercial operation, PG&E requests authority to file an expedited advice letter to update the initial revenue requirement to reflect the current Commission-authorized cost of capital, franchise and uncollectibles factors, and property tax factors. If subsequent Commission decisions adopt changes to these factors before the next General Rate Case following commercial operation, PG&E requests authority to update the initial revenue requirement.

DRA's Analysis and Recommendation

PG&E's requested method to update revenue requirement factors is reasonable and consistent with Commission practice.²⁴ Therefore, DRA does not oppose PG&E's request to update the initial revenue requirement by advice letter.

2.2. Transmission Upgrades

In the event that it must finance network transmission upgrades, PG&E requests authority to adjust the initial revenue requirement to allow collection of any difference between the interest rate used to reimburse PG&E and its finance costs at its then-authorized weighted average cost of capital on a pre-tax basis.²⁵ PG&E would reflect this adjustment in the Manzana Wind Project memorandum account.

DRA's Analysis and Recommendation

DRA does not oppose PG&E's request regarding transmission upgrades.

2.3. Changes in Renewable Tax Credits

PG&E makes several requests regarding renewable tax credits. First, PG&E requests authority to elect between the Investment Tax Credit ("ITC") or the Production Tax Credit ("PTC") at the time the Project is placed in service based upon the best information currently available.²⁶ Second, PG&E requests authority to adjust the initial revenue requirement if the ITC or PTC is modified. Lastly, PG&E requests authorization

²⁴ D.06-11-048, p. 23.

²⁵ PG&E Direct Testimony, pp. 7-4.

²⁶ PG&E Direct Testimony, pp. 7-4 to 7-5.

1 to proceed with the Project even if it is ineligible to receive the ITC or PTC (which may
2 result if the Project is delayed beyond December 31, 2012 and the ITC or PTC is not
3 extended). PG&E requests authority to track these adjustments in the Manzanita Wind
4 Project memorandum account.

5 **DRA's Analysis and Recommendation**

6 DRA recommends that the Commission require PG&E to file an advice letter,
7 preferably at Tier 2 or a higher level, regarding: (1) the election between the ITC or PTC
8 and (2) any adjustment to the initial revenue requirement if the ITC or PTC is modified.
9 The election between the ITC and PTC is a particularly important decision that will
10 strongly impact Project costs, and therefore ratepayers. After-the-fact reasonableness
11 review by way of a memorandum account is not appropriate for such an important
12 decision. Therefore, the Commission should adopt a process that allows interested
13 parties an opportunity to affect the decision prior to the election.

14 Lastly, DRA opposes the Commission granting PG&E the authority to increase the
15 Project's approved revenue requirements if it is ineligible for either the ITC or PTC
16 (which could occur if the Project is delayed beyond December 31, 2012 and the ITC or
17 PTC is not extended). The application of the ITC or PTC is critical to the cost-
18 effectiveness of the Project. Without either the ITC or PTC, the levelized cost of energy
19 for the Project will XXXXXXXXXXXX comparable wind or even solar photovoltaic
20 projects. DRA therefore recommends that the Commission not approve the Project
21 without assurances that it will be completed on-time to receive the ITC or PTC or require
22 PG&E's shareholders to bear the risks of losing the ITC or PTC.

23 **E. PG&E'S PROPOSAL TO DECREASE INITIAL CAPITAL COSTS AND** 24 **EXPENSES DUE TO DECREASES IN PROJECT CAPACITY**

25 PG&E acknowledges that, although the expected capacity of the Project is
26 246 MW, it is possible that the ultimate Project capacity will be less than 246 MW and
27 may be as low as 189 MW.²⁷

²⁷ PG&E Direct Testimony, p. 1-2.

1 **1.1 Revised Initial Capital Cost Estimate if Final Project**
2 **Capacity is Less than 246 MW**

3 PG&E proposes lowering the initial capital cost estimate by \$XX million per MW
4 if the actual installed capacity is less than 246 MW.⁹⁸ Such a reduction would decrease
5 the initial revenue requirement by \$XXXX per MW.⁹⁹ This decrease would be reflected
6 in the Manzana Wind Project memorandum account.

7 **DRA’s Analysis and Recommendation**

8 DRA opposes Commission approval of the Application if the Project is not built
9 out to the full 246 MW, because the Project is not cost effective at the lower capacity.
10 Assuming Commission approval is forthcoming, however, granting PG&E the authority
11 to revise the initial capital cost and initial revenue requirement appears reasonable with 2
12 modifications. The Commission should require PG&E to *further* reduce the total capital
13 costs by \$XXXXX—the amount of PG&E’s XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
14 XXXXXXXXXXXXXXXX—unless PG&E definitely commits to XXXXXXXXXXXXXXXX
15 XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX. Also, the per-MW cost reduction
16 amount will need to be recalculated depending on whether the Commission disallows or
17 adjusts PG&E’s proposed ratemaking treatment for any of the cost components that affect
18 PG&E’s per-MW cost calculation.

19 First, PG&E’s estimated cost reductions of \$XXXXXXXXXX for a reduced Project
20 capacity assume that Iberdrola Renewables XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
21 XX.¹⁰⁰
22 Under the PSA and PCA, Iberdrola has XXXXXXXXXXXXXXXX to obtain and provide land
23 rights and development permits for some of all of the incremental 57 MW of capacity XX
24 XX.¹⁰¹ In

⁹⁸ PG&E Direct Testimony, pp. 7-6.

⁹⁹ Id.

¹⁰⁰ See Exhibit NN - Data Response DRA_001-Q12 and DRA_001-Q12 Attachment1 (cost breakdown showing permitted land at \$XXXXX. If the project is 189 MW, the cost for permitted land not needed for the project totals \$XX million).

¹⁰¹ PG&E Direct Testimony p. 2-8 lines 12-13.

1 this scenario, PG&E will pay Iberdrola [REDACTED]
2 [REDACTED]
3 [REDACTED]
4 [REDACTED]¹⁰² Thus, if Iberdrola secures
5 land rights and development permits for a 246 MW Project capacity but [REDACTED]
6 [REDACTED] only a 189 MW Project capacity, PG&E will pay [REDACTED] for land that is [REDACTED]
7 [REDACTED].

8 This portion of the cost payment to Iberdrola (if made) should *not* be placed into
9 rate base [REDACTED] of
10 [REDACTED] within five years. PG&E proposes to add this \$[REDACTED] into
11 rate base [REDACTED]
12 [REDACTED].¹⁰³ However, the Commission’s guidelines for determining if Plant
13 Held for Future Use (“PHFU”) property may be included in a utility’s rate base require
14 that “[a]ll items in PHFU must have a specific plan *for use*”¹⁰⁴—not a plan for “[REDACTED]
15 [REDACTED]” use. DRA therefore recommends that, if PG&E acquires land rights for the
16 incremental 57 MW [REDACTED], PG&E should
17 track the costs incurred or associated with holding the property for potential future use in
18 a memorandum account. If PG&E commits to a specific plan and timeline to develop the
19 incremental 57 MW of capacity, it may then request recovery of such costs in rate base as
20 PHFU in accordance with the Commission’s guidelines. DRA estimates that in the event
21 the \$[REDACTED] million for [REDACTED] is disallowed from the rate base, PG&E
22 should reduce Project costs by \$[REDACTED] million/MW of un-built capacity.¹⁰⁵

23 Second, PG&E’s estimated cost reduction of \$[REDACTED] million per MW may change
24 if the Commission disallows proposed costs or adjusts PG&E’s proposed ratemaking
25 treatment for any of the items on which the calculation depends. For example, if the

¹⁰² PG&E Direct Testimony p. 2-3 lines 17-21 (emphasis added).

¹⁰³ PG&E Direct Testimony p. 2-8 lines 20-1 to 21.

¹⁰⁴ D.87-12-066, mimeo. Appendix B (emphasis added).

¹⁰⁵ This reflects an additional reduction of \$[REDACTED] million per MW (\$[REDACTED]/kW).

Commission reduces PG&E's costs or PG&E's estimated O&M costs to reflect a smaller installed Capacity, the per-MW price reduction may increase.¹⁰⁶

1.2. Revised O&M Costs if Final Project Capacity is Less than 246 MW

PG&E's proposal provides for reducing the costs for post-commercial operations costs if the final Project capacity is less than 246 MW.¹⁰⁷ PG&E has not indicated that a similar reduction will occur to pre-commercial operations costs. If the final Project capacity is lower than 246 MW, then pre-commercial operations costs should also be reduced. A 189 MW Project will consist of 126 turbines, 38 less turbines than required for a 246 MW capacity. A smaller number of turbines should result in reductions to staffing levels, materials, equipment and any associated training budgets—both for pre and post-commercial operations.

PG&E indicated, based on a final Project capacity of 189 MW, that post-commercial operations costs would be reduced by approximately XXX percent during the first year of operations.¹⁰⁸ In order to reflect the lower costs of the lower capacity project, DRA recommends that the Commission reduce the pre-commercial operations costs by the same XXX percent if the final Project capacity is 189 MW. If the final Project capacity is not 189 MW or 246 MW, DRA recommends that the Commission proportionately reduce pre-commercial operations costs to reflect the final project capacity.

¹⁰⁶ See Exhibit J - Data Response DRA_001-05.

¹⁰⁷ See Exhibit OO - Data Response DRA_001_003.

¹⁰⁸ See Exhibit OO - Data Response DRA_001_003.

CHAPTER 4 – COST COMPETITIVENESS

A. RANGE OF LEVELIZED COSTS OF ENERGY AND NET PRESENT VALUES FOR THE PROJECT UNDER DIFFERENT SCENARIOS

PG&E calculates the levelized cost of energy of the Project as \$XXX/MWh¹⁰⁹ (\$XXX/MWh on a time-of-day adjusted basis, with a transmission adder of \$XXX/MWh).¹¹⁰ PG&E calculates the Project's net market value to be XXXXXXXX.¹¹¹ These results, however, reflect a variety of optimistic cost and operating assumptions that will likely not turn out as favorably as PG&E hopes. Unlike with a power purchase agreement in which the cost of energy is contractually determined and increases are subject to Commission review and approval, the actual levelized cost of energy could be much higher than PG&E has calculated and the net present value much lower. A number of factors could lead to costs increases or revenues that are lower than predicted:

- the installed capacity is only 189 MW, rather than 246 MW;
- the actual capacity factor is less than 31.1 percent or declines over time as the turbines age;
- the Project's capacity is reduced due to mitigation measures that may be necessary to reduce risks to endangered species;
- the commercial operations date is delayed beyond PG&E's assumed date of December 31, 2011 and PG&E is allowed to pass the resulting cost increases on to ratepayers;
- the total project costs are increased due to other factors (such as operational enhancements, change scope orders, required transmission upgrades, or updated revenue requirement factors) and PG&E is allowed to pass the resulting cost increases on to ratepayers;

¹⁰⁹ PG&E Direct Testimony at 7-14.

¹¹⁰ PG&E Errata to D Testimony, p.1.

¹¹¹ See id. and Exhibit PP – Data Response TURN_002-04 (identifying errors in net market value of the Project reported in PG&E Direct Testimony).

- the Project’s useful life is less than 30 years;
- the Project is ineligible for the Investment Tax Credit or Production Tax Credit.

Under PG&E’s proposed ratemaking, ratepayers bear *all* of the risks that the Project’s economics will be adversely affected for any of the reasons listed above. The Commission should therefore consider the range of potential levelized costs of energy and net market values when evaluating whether the Project is cost effective compared to other wind energy opportunities. DRA believes that the Project, as proposed, is *not* cost effective for a wind project—even using PG&E’s own assumptions, as explained in Section C below. But the Manzana Wind Project’s economics look even worse if PG&E’s assumptions are varied to reflect plausible operations scenarios.

The impacts of modifying even some of PG&E’s assumptions are significant. For example, as PG&E’s Independent Evaluator noted, ~~XXXXXXXXXXXXXXXXXXXX~~
~~XX~~
~~XX~~.¹¹² The Independent Evaluator performed a sensitivity analysis assuming that (1) the installed capacity is 189 MW and (2) the assumed capacity factor is reduced only slightly to ~~XXX~~ percent—the likely capacity factor calculated by PG&E’s wind resource and technical expert, DNV Global Energy Concepts. Changing just these two assumptions alone ~~XXXX~~ the net market value of the Project to ~~XXXXXXXXXX~~.¹¹³

In response to data requests and the Commission’s Scoping Memo, PG&E has calculated alternative levelized costs of energy and net market values for the Project under different operating assumptions. The results reveal the following economic impacts based on the following changes in assumptions:

¹¹² PG&E Direct Testimony, Appendix 3.2-C, Table A-3 at A-4.

¹¹³ See PG&E Errata to Prepared Testimony, p.2 and Exhibit ZZ - Data Response TURN_001-14.

(1) Revised net capacity factor: If the Project operates at a lower net capacity factor than the assumed 31.1 percent, revenues will decline and the levelized cost of energy will increase to:

- \$XXXXXXX using a 26.0 percent capacity factor – the net capacity factor developed from 2005 actual wind generation data for the Tehachapi area.¹¹⁴
- \$XXXXXXX using a XXX percent capacity factor – the estimated capacity factor by PG&E’s meteorological expert DNV Global Energy Concepts.¹¹⁵

[illegible]

¹¹⁴ PG&E Supplemental Direct Testimony at 8-5.

¹¹⁵ PG&E Supplemental Direct Testimony at 8-3.

¹¹⁶ See Exhibit QQ – Data Response TURN_001_15.

¹¹⁷ See Testimony Appendix 3.2-C, at A-4; PG&E's Supplemental Testimony at 8-2 to 8-3, and Exhibit QQ - Data Response TURN 001-15

¹¹⁸ See Exhibit QQ - Data Response TURN 001-15, Attachments 2, 3, 4, and 5.

¹¹⁹ PG&E Direct Supplemental Testimony at 8-3.

120 Id.

¹²¹ Exhibit QQ - Data Response TURN 001-15-CONF-Attachment5 (“EMF Comments” in right-most

1 these analyses assume that the net capacity factor of the Project will remain a constant
2 31.1 percent,¹²² but higher than expected turbine fatigue and component failures could
3 reduce the net capacity factor over the lifetime of the Project, particularly if it is assumed
4 to be 30 years XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX.¹²³

5 As PG&E's responses to the Commission's Scoping Memo and various data
6 requests indicate, there is simply a great deal of uncertainty associated with calculating a
7 wind plant's net capacity factor over the 20 to 30-year lifespan of the project. The real-
8 world generation of the Project could very likely turn out lower than PG&E has assumed;
9 yet under PG&E's ratemaking proposal, there are no guarantees or even incentives that
10 the Project will perform as well as PG&E predicts.

11
12 (2) Delays in Commercial Operations: As DRA explained in Chapter 3,
13 Section B.1.1, the Project is virtually certain to be delayed until XXXXXXXXXX at the
14 *earliest*, due to the expected date of completion of Tehachapi Renewable Transmission
15 Project, Segment 4. Delays could plausibly stretch on until XXXXXXXXXXXXXXXX
16 XX
17 XX. Further, additional permitting,
18 mitigation requirements or legal challenges based on threats posed to endangered species
19 that are known to inhabit areas near the Project could delay construction and/or operation
20 for years.

21 Any delay will significantly increase the total Project costs to ratepayers under
22 PG&E's proposed ratemaking, as explained in Chapter 3, Section B.1.1. If PG&E passes

column, first two rows).

¹²² See, e.g., Exhibit QQ - Data Response TURN_001-15-CONF-Attachment5 ("EMF Comments" first row, explaining that XX XX XX).

¹²³ See Exhibit RR - Data Response TURN_001-15-CONF-Attachment1 (DNV Global Energy Concepts, Inc. Report) at 18 (noting that XX XX XXXXXXXXXXXXXXXXXXXXXXXX).

the costs of delays on to ratepayers, the levelized cost of energy for a 246 MW Project would increase to:

- \$XXXXXX/MWh if commercial operations start in mid-April, 2012;
- \$XXXXXX/MWh if commercial operations start in mid-August, 2012.¹²⁴

(3) Installed capacity is less than 246 MW: As the Independent Evaluator’s sensitivity analysis revealed, the Project’s economics XXXXXXXXXX to the installed capacity assumption. If the Project is built to only 189 MW—assuming all other factors are equal—the levelized cost of energy increases to \$XXXXX/MWh.¹²⁵ PG&E’s ratemaking proposal does not provide any guarantees that the project will ultimately be built to the full 246 MW.

(4) Plant useful life is 20 years, not 30 years: PG&E has assumed that the Project will have a useful life of 30 years, but has not provided any explanation or evidence to support this assumption beyond stating that “PG&E believes that the Manzana project will operate for 30 years.”¹²⁶ The actual useful life could be shorter.

First, PG&E could determine that there is a need to repower the turbines to incorporate improved wind turbine technology that increases the energy output of the Project's land area (particularly if available land for wind energy projects becomes scarce) or to address challenges to maintaining the reliability of the electricity transmission as California integrates larger amounts of intermittent wind resources. Repowering may become an economically attractive alternative because operations and maintenance costs for turbines increase as the turbines age and experience fatigue and component failures. Indeed, PG&E's

¹²⁴ See Exhibit SS – Data Response DRA_001_Q23-CONF-Rev02.

125 Id.

¹²⁶ Exhibit TT - Data Response DRA 003-03.

XXXXXXXXXXXXXXXXX.¹²⁷ The consultant estimated that operations and maintenance costs for the turbines will increase by nearly \$XXX per turbine in years XXX compared to years XXXX.¹²⁸

Second, PG&E may be unable to renew the leases to land which the turbines are situated when they begin to expire in year XXX, or PG&E may determine it is more cost-effective to remove the aging turbines than to pay undetermined increased costs for new lease agreements.¹²⁹ According to PG&E, the leases to the land on which XX turbines sit will expire in year XX of the Project's operations.¹³⁰ Further, as Table 4-1 below indicates, by year XXX, or year XX of the Project's life, leases will have expired for the land on which over XXX of the turbines are located. While PG&E may intend to negotiate lease extensions, it has no guarantee that landowners will agree. Nor has PG&E given a rational basis for its assumption that in X years, the lease costs will be no more than XXXXX the prices negotiated in XXXX.

Table 4-1. Land Lease Expirations.

Year	Operations Year	Number of Leases Expiring in Year	Number of Turbines Located on Land with a Lease Expiring in Year	Cumulative Number of Turbines on Land for Which the Lease has Expired	Percentage of total Turbines (246 MW Project) on Land for Which the Lease has Expired
XXX	XX	XX	XX	XXX	XXX
XXX	XX	XX	XX	XXX	XXX
XXX	XX	XX	XX	XXX	XXX
XXX	XX	XX	XX	XXX	XXX
XXX	XX	(data not provided for years XXXX and beyond)			

¹²⁷ Exhibit RR - Data Response TURN_001-15-CONF-Attachment1 (DNV Global Energy Concepts, Inc. Report) at 18, 25 (conclusion 7).

¹²⁸ Id. at 23-24.

¹²⁹ See Exhibit UU - Data Response DRA_003-04; Exhibit VV - Data Response TURN_001-01. PG&E has estimated that the cost of extending any lease could be up to XXXXXX the existing cost for each lease. The annual cost of leases is estimated at \$XXX million. See Id.; See also PG&E Direct Testimony at 7-9 (yearly initial revenue requirement for lease payments is \$XXXX).

¹³⁰ See Exhibit UU- Data Response DRA_003-04, DRA_003-Q04-CONF-Attachment1.

1 While PG&E *assumes* a 30-year useful life, its ratemaking proposal provides
2 absolutely no guarantee that the Project will produce energy for a full term of 30 years.
3 PG&E has not included any ratepayer protections, and indeed it may not make good
4 economic sense to continue plant operations toward the end of the Project's useful life.
5 PG&E should determine what is in ratepayers' best interests at the time based on the
6 then-existing state of the wind turbines, land leases, new wind and other renewable
7 technologies, PG&E's renewable energy portfolio, and the regulatory environment. The
8 Commission should consider, however, that if the Project's assumed useful life is reduced
9 to 20 years the levelized cost of energy increases to \$XXXX/MWh for a 246 MW build-
10 out.¹³¹

11
12 (5) PG&E does not receive Investment or Production Tax Credits for the
13 Project: PG&E will not be able to claim the benefits of the Investment Tax Credit or the
14 Production Tax Credit if the Project is delayed beyond December 31, 2012 and neither of
15 these tax credits is extended by Congress.¹³² The Independent Evaluator noted that the
16 tax credits are considerable and estimated that they are worth approximately XXXXXX
17 to PG&E's customers.¹³³ Delays beyond 2012 are certainly possible given the concerns
18 expressed by advocacy groups *and* state and federal wildlife regulators about threats to
19 endangered species located on or in the vicinity of the Project. If state or federal
20 regulators require additional environmental studies or permitting requirements, or if any
21 group institutes a legal challenge to stop construction or operations, the Project could be
22 delayed beyond December 31, 2012.

23 If the Project is delayed one year and becomes operational after December 31,
24 2012 and is ineligible for the Investment or Production Tax Credit the levelized cost of
25 energy will increase to:

- 26 • \$XXXX/MWh for a 246 MW Project capacity;

¹³¹ See Exhibit TT - Data Response DRA_003-Q03.

¹³² See PG&E Direct Testimony at 7-5.

¹³³ PG&E Direct Testimony, Appendix 3.2-C at A-8.

- \$XXXX/MWh for a 189 MW Project capacity.¹³⁴

(6) Combined changes to PG&E's operating assumptions:

The economic impacts of *cumulative* changes to the Project's operating are even more significant than those discussed above. The following table summarizes a range of potential levelized costs of energy and net market values (to the extent they have been provided by PG&E) assuming different combinations of changes in the Project:

Table 4-2. Levelized Cost of Energy and Net Market Value Under Different Scenarios - 189 MW Project Capacity.¹³⁵

Delay (No. months)	Commercial Operations Date	Net Capacity Factor (percent)	Useful Life (years)	Levelized Cost of Energy (\$/MWh)	Net Market Value (\$/MWh)
0	12/31/11	XXX	20	XXXX	
3.5 mo	4/15/12	XXX	20	XXXX	XXXX
6.5 mo.	7/15/12	31.1	30	XXXX	XXXX
7.5 mo.	8/15/12	XXX	20	XXXX	XXXX
12 mo. NO ITC	1/1/13	31.1	30	XXXX	XXXX

¹³⁴ See Exhibit SS - Data Response DRA_001-Q23-CONF-Rev02.

¹³⁵ All values are as reported in Exhibit SS - Data Response DRA_001-Q23-CONF-Rev02 and Exhibit GG - DRA_004-Q01-CONF-Attachment01-Rev01.

Table 4-3. Levelized Cost of Energy and Net Market Value Under Different Scenarios - 246 MW Project Capacity¹³⁶

Delay (No. months)	Commercial Operations Date	Net Capacity Factor (percent)	Useful Life (years)	Levelized Cost of Energy (\$/MWh)	Net Market Value (\$/MWh)
0	12/31/11	XXX	20	XXXX	
3.5 mo	4/15/12	XXX	20	XXXX	XXXX
7.5 mo.	8/15/12	XXX	20	XXXX	XXXX
12 mo. NO ITC	1/1/13	31.1	30	XXXX	XXXX

B. THE INDEPENDENT EVALUATOR AND PG&E COMPARED MANZANA TO NON-WIND PROJECTS

The Assigned Commissioner’s Ruling and Scoping Memorandum, states that, “The Commission must determine whether the Project’s proposed capital cost and operating costs are reasonable and competitive with other similar renewable wind resources.”¹³⁷ Both PG&E and its Independent Evaluator compared this Project to *all* types of renewable energy technologies when declaring the Project to be cost competitive.¹³⁸ This ignores the fact that wind is among the cheapest renewable resources. Considering more expensive non-wind resources such as solar thermal, solar photovoltaic and *space solar* makes the Project look more favorable from a cost perspective than it actually is.

In declaring the Project to be cost competitive, PG&E and the Independent Evaluator compared the Project to power purchase agreements that were executed or amended and filed within the past 12 months, and long-term projects that PG&E included

¹³⁶ All values are as reported in Exhibit SS - Data Response DRA_001-Q23-CONF-Rev02 and Exhibit GG - DRA_004-Q01-CONF-Attachment01-Rev01.

¹³⁷ Assigned Commissioner’s Ruling and Scoping Memorandum, March 25, 2010, p.4.

¹³⁸ See PG&E Direct Testimony Tables 4-1 and 4-2 and the Independent Evaluator’s Table A-2 at Appendix 3.2-C (IE Report).

1 on its shortlist following the 2009 Request for Offers – for *all* types of renewable energy
2 projects.¹³⁹ PG&E did later serve supplemental testimony, as ordered by the
3 Administrative Law Judge, that showed only the wind resource contracts and offers from
4 Tables 4-1 and 4-2 of its analysis of cost competitiveness.¹⁴⁰ PG&E did not, however,
5 “restrict the comparison of Manzana only to other wind resources *but otherwise[]*
6 *replicate[] the analysis* performed in chapter 4” as requested in the Commission’s
7 Scoping Memo.¹⁴¹ It is easy to see that the Project’s time-of-day adjusted levelized cost
8 of energy is more XXXX than XX of the XX wind contracts and offers summarized in
9 PG&E’s supplemental testimony.

10 Moreover, although the Independent Evaluator conducted a limited sensitivity
11 analysis and calculated net present value and levelized cost of energy assuming the
12 Project has a lower installed capacity and capacity factor, the Evaluator did not consider
13 other factors that could adversely affect the Project’s economics, such as cost increases
14 due to delay or violations of environmental laws, a shorter (20-year) useful life, or lower
15 installed capacity and capacity factors. The Evaluator should have analyzed the feasible
16 range of net present values and levelized costs of energy for the project and compared
17 these values to other proposed wind projects.

18 Finally, PG&E and its Independent Evaluator did not consider other data sources
19 when considering the Project’s cost or cost effectiveness. In the following Section DRA
20 examines the Project compared to other wind projects and industry data on wind prices
21 and costs.

22 **C. DRA’S ANALYSIS OF COST COMPETITIVENESS COMPARED TO** 23 **OTHER WIND PROJECTS**

24 DRA compared the Project’s levelized cost of energy with (1) wind project prices
25 from other power purchase agreements between PG&E and Iberdrola, (2) *all* wind
26 projects in PG&E’s own portfolio for which price information is available, (3) the

¹³⁹ PG&E Direct Testimony Appendix 3.1, 3.2-C, and Chapter 4.

¹⁴⁰ PG&E Supplemental Testimony Table 4-3 at page 4-6 and Table 4-4 at page 4-7.

¹⁴¹ Assigned Commissioner’s Ruling and Scoping Memorandum, March 25, 2010, p.7 (emphasis added).

1 average price of wind contracts in each of the three investor-owned utilities' portfolios,
2 and (4) industry data on wind project prices. DRA's analysis finds that almost all
3 currently proposed and installed wind projects in California are XXXXXXXXX the
4 proposed Project on a levelized cost of energy basis.

5 DRA's analysis below is performed using PG&E's proposed time-of-day adjusted
6 levelized cost of energy of \$XXXX/MWh¹⁴² for the Project. The transmission adder of
7 \$XXX¹⁴³ is subtracted for a Project price of \$XXX/MWh to make for a fair comparison
8 to prices in power purchase agreements, which do not include a transmission adder.
9 However, as explained in Section A above, the actual levelized cost of energy could be
10 much higher than this value.

11 1. Other Wind Power Purchase Agreements Between 12 Iberdrola and PG&E

13 PG&E has considered at least XXXX other wind projects developed by Iberdrola,
14 three of which are now online. Shiloh I, a XX-year contract between PG&E and
15 Iberdrola, came online in 2006 and provides 75 MW at a levelized cost of energy of
16 \$XXX/MWh.¹⁴⁴ Klondike III came online in 2007, will provide 85 MW for XX years at
17 \$XXX/MWh.¹⁴⁵ Klondike IIIa is a XX-year contract providing 90 MW, came online in
18 2009 and has a levelized cost of energy of \$XXX.¹⁴⁶ XXXXXXXXXXXXXXXXXXXXXXXX
19 XX.¹⁴⁷ XXXXXXXX
20 XX.¹⁴⁸ XX
21 XX
22 XXXXX.

¹⁴² PG&E Errata, p.1.

¹⁴³ PG&E Errata, p.1.

¹⁴⁴ See Exhibit AAA – Data Response DRA-04-02-CONF-Attachment01.

¹⁴⁵ Id.

¹⁴⁶ Id.

¹⁴⁷ PG&E March 2010 Compliance Report.

¹⁴⁸ PG&E March 2010 Compliance Report.

1 **2. Other Wind Contracts PG&E Has Executed or Is**
2 **Considering**

3 DRA analyzed wind contract data from PG&E's March 2010 Renewable Portfolio
4 Standard Compliance Report. DRA's analysis demonstrates that the Project is not nearly
5 as good of a deal for ratepayers as PG&E claims, and in fact it is one of the XXXXX
6 XXXXXXXXXX wind projects in PG&E's entire portfolio which, as of the March 2010
7 Compliance report, contains 40 wind projects.¹⁴⁹ Among these 40 wind projects, contract
8 prices are available for 27.¹⁵⁰ Almost a third of those are already online and the majority
9 of the rest are waiting for Commission approval. The Manzana Wind Project would rank
10 XX out of these 27.¹⁵¹ The mean contract price for these 27 projects is \$XXXX, with a
11 standard deviation of \$XXXX. Thus, the average contract price for PG&E's other wind
12 projects is XX% less than the Manzana Wind Project's price of \$XXXX, which is almost
13 XXXXXXXXXXXXXXXXXXXX above the mean for this group. Further, the only XX projects
14 that are XXXXXXXX the Manzana Wind Project are both about XXXXXXXXXXXX.

15 Again, this analysis assumes that PG&E's levelized cost of energy is \$XXXX as
16 PG&E's claims—while it could realistically be more in the range of \$XXXX/MWh.¹⁵²
17 If the Project's levelized cost of energy is above \$XXXX/MWh, it will rank XXXXXX.

18 Moreover, PG&E is negotiating power purchase agreements with other wind
19 project developers that are XXXXXXXX this proposed Utility Owned Generation
20 Project's levelized cost of energy. XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
21 XX
22 XXXXXX.¹⁵³ XX
23 XX
24 XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX. Even using PG&E's optimistic

¹⁴⁹ PG&E's March 2010 Compliance Report.

¹⁵⁰ Id.

¹⁵¹ Id.

¹⁵² PG&E Direct Testimony, Revised February 3, 2010, p. 7-14.

¹⁵³ Exhibit WW - PG&E's Procurement Review Group Presentation, April 9, 2010.

1 estimate of \$XXXX/MWh for this Project, XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
2 than the Project despite XXXXXXXXXXXXXXXXXXXXXXXX. The price XXXXX is even
3 more glaring given the difference in the XXXXX of the projects. At more than XXXX
4 XXXXXXXXXXXXXXXX, this Project should have captured additional economies of scale.

5 PG&E's latest Procurement Review Group presentation from April 9, 2010
6 includes XX
7 XX
8 XX
9 XX
10 XX
11 XX
12 XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX.

13 PG&E also indicated that it is considering entering into several wind projects via
14 bilateral transactions. XX
15 XX
16 XX
17 XXXXXXXX.

18 As DRA's analysis demonstrates, the proposed cost of the Manzana Wind Project
19 is much less competitive than PG&E claims when compared to *similar* renewable
20 resources.¹⁵⁴

21 3. Wind Projects In the Other Investor Owned Utilities' 22 Portfolios

23 DRA also evaluated the Project compared to the average wind contract prices of
24 Investor Owned Utilities for which price information is available. First, overall, PG&E's
25 wind portfolio prices XXXXXXX to the other Investor Owned Utilities ("IOUs"), as
26 shown in Table 4-4 below. This table reports the average proposed and final wind

¹⁵⁴ PG&E Direct Testimony, Chapter 4.

contract prices for the three utilities using the March 2010 and August 2009 Compliance Reports.

Table 4-4. Wind Contract Price Averages For Different Utilities

Wind Contract Price Averages					
		Proposed Price	Contract Price	Number of contracts*	
March 2010 Compliance Reports	PG&E	XXXXXX	XXXXXX		XX
	SCE	XXXXXX	XXXXXX		XX
	SDG&E	XXXXXX	XXXX		XX
August 2009 Compliance Reports	PG&E	XXXXXX	XXXX		XX
	SCE	XXXXXX	XXXX		XX
	SDG&E	XXXX	XXXXXX		XX

* not all contracts had a Proposed and/or Contract Price available

As Table 4-4 demonstrates, PG&E's average proposed and actual contract prices - as reported in the IOU's March 2010 compliance reports -- XXXXXXXXXXXXXXXXXXXX SDG&E and SCE's. The levelized time-of-day adjusted price of the Project, however, XXXXXXXXXXXXXXXX to the average for any utility's portfolio, and is XX percent XXXXXXXX than the average for SCE's and is XX percent XXXXXX the average for SDG&E.

4. Independent Industry Reports of Wind Project Costs and Prices

Reports prepared by independent renewable industry consultants also suggest that the Manzana Wind Project is more XXXX than reported data or industry estimates for other wind projects.

Consultant Black & Veatch prepared a Draft Report for the California Renewable Energy Transmission Initiative ("RETI"). The Phase 2B report, released in April 2010, states, "wind project costs have declined recently due to the global recession and slackening of demand growth relative to new manufacturing additions."¹⁵⁵ The Report

¹⁵⁵ Renewable Energy Transmission Initiative Phase 2B Draft Report, April 2010, available at http://www.energy.ca.gov/reti/documents/phase2B/RETI_Phase_2B_Draft.pdf. p. 4-4

1 found the levelized cost of wind to be between \$60 and \$113/MWh.¹⁵⁶ Further, an
2 analysis of wind energy prices nationwide prepared by Lazard in February 2009 (Version
3 3.0) estimated nationwide levelized costs of energy for wind projects to range between
4 \$57 and \$113 per megawatt-hour.¹⁵⁷

5 Notably, these studies report consistent installed project costs and estimated
6 levelized costs of energy for wind projects. By comparison, the Project is again proven
7 XXXXX, more than XXXXXXXX than even the XXXXX of both reports. Again, this
8 analysis does not reflect the possibility that the Project's actual levelized cost of energy
9 will be much higher than PG&E's estimate.

10 The Project also does XXXXX compared to the industry reports on an installed
11 costs per kilowatt basis. For example, the Department of Energy's Annual Report on
12 U.S. Wind Power Installation, Cost, and Performance Trends: 2007 reported that "among
13 the sample of projects built in 2007, reported installed costs ranged from \$1,240/kW to
14 \$2,600/kW, with an average cost of \$1,710/kW" and predicted an increase to \$1,920/kW
15 the following year.¹⁵⁸ In the report prepared for the RETI project, Black & Veatch
16 assumed total project costs range from \$2,150 to \$2,600 per kilowatt for wind resources,
17 with Operations and Maintenance adding another \$18 to \$25 per megawatt-hour.¹⁵⁹ The
18 Lazard study estimates that capital costs for wind projects range from \$1,900 to \$2,500
19 per kilowatt.¹⁶⁰

20 The installed cost per kilowatt of the Manzanita Wind Project is XXXXXXXXXXXX
21 estimates from these two reports. Removing the \$XXX million of total O&M costs
22 included in the \$911 million proposed initial capital cost for the Manzanita Wind
23 Project,¹⁶¹ the Project's total cost is \$XXXX million—and that generously assumes that

¹⁵⁶ Id., p. 1-2.

¹⁵⁷ Exhibit BBB – Lazard Levelized Cost of Energy Analysis – Version 3.0 (February 2009) Slide 2.

¹⁵⁸ Exhibit N at 21.

¹⁵⁹ RETI Phase 2B Draft Report, April 2010, p. 4-4.

¹⁶⁰ Exhibit BBB – Lazard Levelized Cost of Energy Analysis – Version 3.0 (February 2009), slide 9.

¹⁶¹ PG&E Direct Testimony, p. 5-3 through 5-7.

PG&E does not incur *any* cost increases due to delays or any other factors. At a full 246 megawatt build-out—another assumption that is not guaranteed—the Project cost is \$XXXX per kilowatt. That is XX percent more XXXXXX than even the XXXXX of the Black & Veatch model’s assumptions for wind.

5. The Project Is Significantly XXXXXXXX Than the Market Price Referent

Manzana also XXXXXXXX when compared to the Market Price Referent established by the Commission. Manzana’s 20-year levelized cost of energy is \$XXXX/MWh.¹⁶² The 2009 Market Price Referent for 20-year contracts that come online in 2011 is \$100.98/MWh and \$105.07/MWh for projects coming online in 2012. Manzana’s time-of-day adjusted 30-year levelized cost of energy, with the transmission adder subtracted, is \$XXXX/MWh. There is no Referent for 30-year contracts but there is one for 25 years and, in 2009, it is \$104.42/MWh for projects coming online in 2011 and \$108.52/MWh in 2012. The Project is considerably XXXXXXXX than any Market Price Referent one can look to for comparison.

D. RISKS OF UTILITY-OWNED GENERATION

The Manzana Wind Project does XXXXXXXX when compared to other wind projects in PG&E territory, across California, nor on a national level. It fails to make sense from a cost perspective on all levels of comparison and, given additional uncertainties, such as possible Endangered Species Act violations, delay costs and capacity factor assumptions, it simply does not make sense for ratepayers as currently proposed.

Moreover, under PG&E’s proposal purchase and operate the Project as utility owned generation ratepayers bear *all* risks of underperformance—which could occur if the Project’s installed capacity is less than 246 MW or if the actual capacity factor is less than 31.1 percent. Ratepayers also bear all of the risks that the Project could be partially or completely shut down to comply with the federal or California endangered species

¹⁶² Exhibit TT – Data Response DRA_003-Q03.

1 acts—leaving ratepayers saddled with a plant costing nearly \$1 billion dollars in rate
2 base. Further, under PG&E’s ratemaking proposal, ratepayers *also* bear *all* of the risk of
3 cost overruns due to delay, change scope orders, or other factors. Yet, if the Project were
4 executed as a power purchase agreement, ratepayers would bear none of these risks—or
5 the Commission would at least review proposed price increases and consumer groups
6 would have an opportunity to intervene. In light of the substantial risks to ratepayers
7 associated with placing the plant into rate base, the Project should be priced *lower* than
8 the price for comparable wind energy under power purchase agreements offered by
9 private developers.

10 While the Commission may have stated some interest in encouraging utility
11 owned generation of renewable energy resources, in this instance it is significantly more
12 expensive compared to power purchase agreement offers by private developers. Further,
13 the Project was *not* subjected to any competitive solicitation process—Iberdrola simply
14 approached PG&E and the two parties negotiated over a final installed price per kilowatt
15 and other terms of the services and assets to be included in the agreement. Yet, private
16 developers are proposing very similar—and in the case of XXXXXXXX, almost
17 identical—projects at lower prices. It appears that ratepayers would benefit more, in both
18 the short- and long-term, if the Commission rejected this application for Utility Owned
19 Generation and instead approved RPS compliance through power purchase agreements
20 with private developers. In the short-term ratepayers would pay lower prices and in the
21 long-term could enjoy a well-developed and competitive marketplace for renewable
22 energy.

APPENDIX A

QUALIFICATIONS AND PREPARED TESTIMONY OF YULIYA SHMIDT

CERTIFICATE OF SERVICE

I hereby certify that I have this day *served* a copy of **DRA TESTIMONY ON PG&E'S APPLICATION FOR APPROVAL OF THE MANZANA WIND PROJECT AND ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY *PUBLIC VERSION*** to the official service list in **A.09-12-002** by using the following service:

☒ **E-Mail Service:** sending the entire document as an attachment to all known parties of record who provided electronic mail addresses.

☒ **U.S. Mail Service:** mailing by first-class mail with postage prepaid to all known parties of record who did not provide electronic mail addresses.

Executed on **April 23, 2010** at San Francisco, California.

/s/ ROSCELLA V. GONZALEZ

Roscella V. Gonzalez

SERVICE LIST
A.09-12-002

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